AIR QUALITY PERMIT

Issued to: Yellowstone Energy Limited Partnership
1087 West River Street, Suite 230
Boise, ID 83702

Permit #2650-07
Modification Request Received: 06/09/00
Additional Requests Received: 10/02/00, 02/15/01
Department Decision on Modification: 05/31/01
Permit Final: 06/16/01
AFS#111-0023

An air quality permit, with conditions, is hereby granted to Yellowstone Energy Limited Partnership (YELP), pursuant to Sections 75-2-204 and 211, MCA, as amended, and Administrative Rules of Montana (ARM) 17.8.701, *et seq*., as amended, for the following:

SECTION I: Permitted Facilities

A. Location

YELP operates a petroleum coke-fired electrical/steam co-generation facility south of the Exxon Refinery in Billings. The facility generates electrical power, which is sold to the Montana Power Company, and steam, which is supplied to the Exxon facility. YELP is located in the NE¼ of Section 25, Township 1 North, Range 26 East, Yellowstone County, Montana. A complete listing of permitted equipment is contained in the permit analysis.

B. Current Permit Action

The Department of Environmental Quality (department) received, from YELP, a request to modify permit #2650-06. The permit action involves changing the solid petroleum coke sampling frequency (sulfur and heat content) from once per week to once per month, permitting coke processing in the existing Limestone Unloading, Crushing, and Conveying facility, and permitting the unloading and storage of off-site petroleum coke at the Exxon Refinery coke storage area.

SECTION II: Limits and Conditions

A. YELP shall verify the sulfur dioxide emission rate, utilizing continuous emission monitors, on an hourly basis on both the YELP stack and from the Exxon coker process gas received by the YELP facility. The results shall be reported to the department, along with other emissions data, within 30 days of the end of each reporting period. The report shall contain all necessary data from the coker process gas stream, fuel petroleum coke sulfur content, cat slurry oil sulfur content, and the YELP main stack continuous emission monitoring system such that the sulfur dioxide emission reduction is quantifiable on an hourly basis (ARM 17.8.710).

B. The sulfur dioxide emission reduction from the Exxon coker process gas shall be at least 238 tons per calendar year. The short-term hourly offset shall be guaranteed according to the provisions listed in item II.K (ARM 17.8.710).

C. The facility shall burn, in conjunction with petroleum coke fuel and cat slurry oil, all the Exxon process gas in the YELP boilers. YELP shall report to the department, within 24 hours, any time the Exxon coker process gas is diverted away from the fluidized bed boiler facility (YELP). Said report shall include the period of diversion, estimate of process gas diverted, and circumstances explaining the diversion of this stream. Said report shall discuss what corrective actions will be taken to prevent recurrences of the situation and what caused the diversion (ARM 17.8.710).

D. All storage silos, surge bins, hoppers, pneumatic coke truck unloading, limestone crushing, and conveyor systems shall utilize baghouses (bag filters) for particulate emission control (ARM 17.8.715).

E. The limestone load-in hopper (used to load in limestone and coke) and ash load-out operations shall be enclosed and particulate emissions controlled by baghouses (bag filters) (ARM 17.8.710).

F. The Coke Unloading / Crushing / Processing facility shall be completely enclosed and utilize a baghouse to control emissions from the crusher, screen, and associated conveyors (ARM 17.8.715).

G. The Coke Barn and the conveyor system linking the Coke Unloading / Crushing / Processing facility to the Coke Barn shall be enclosed (ARM 17.8.715).

H. The processing of off-site petroleum coke (crushing, handling, and storage) shall take place in the Coke Unloading, Crushing, Processing facility, the Coke Barn, the Limestone Unloading, Crushing, and Conveying facility, and at the existing Exxon Refinery coke storage area only. Off-site petroleum coke means coke that is not produced at the Billings Exxon/Mobil refinery. Specific limits applicable to the processing and storage of off-site coke at the YELP facility are as follows (ARM 17.8.710):

1. The total amount of off-site petroleum coke delivered to YELP shall not exceed 240,900 tons during any rolling 12-month time period, unless, off-site coke is being transported to and stored at the Exxon Refinery coke storage area as specified in Section II.H.2.

2. If off-site petroleum coke is transported to and stored at the Exxon Refinery coke storage area then the following conditions apply (ARM 17.8.710):

   a. The total amount of off-site petroleum coke transported, dumped, and stored at the Exxon Refinery coke storage area shall not exceed 35,000 tons during any rolling 12-month time period.

   b. The total amount of off-site coke delivered to the Coke Barn and Limestone Unloading facility shall not exceed 202,000 tons during any rolling 12-month time period. This limit applies while transporting, dumping, and storing off-site petroleum coke at the Exxon Refinery coke storage area and during the ensuing 12-months after completion of the coke barn or the last dump of off-site coke at the Exxon refinery coke storage area which ever is later.

I. All systems within the facility shall be completely enclosed and controlled such that any pollutant generated does not vent to atmosphere, except as expressly allowed in Item II.L (ARM 17.8.710).

J. YELP shall be subject to, at a minimum, all applicable Standards of Performance for New Stationary Sources (NSPS) provisions, as appropriate, of 40 CFR Part 60, Subpart Da, 60.40a through 60.49a, Standards of Performance for Electric Utility Steam Generating Units (ARM 17.8.340).

K. The construction and operation of the YELP facility required external offsets from the adjacent Exxon refinery. The offsets are provided by the combustion and treatment of the Exxon coker process gas stream, by both an hourly limit on sulfur-in-fuel burned at the refinery on a refinery-wide basis of 0.96 lbs. of sulfur-in-fuel per million BTUs fired and a daily limit on the number of barrels of fuel oil that may be burned at the refinery by all combustion units of 720 barrels per calendar day. The following operating conditions are applicable to the YELP facility:

1. At any time YELP is notified by Exxon that Exxon has exceeded either the hourly sulfur-in-fuel limitation or the daily limit on the number of barrels of fuel oil fired, YELP shall operate its facility in such manner as to ensure the ratio of sulfur dioxide in the Exxon coker process gas stream to the sulfur dioxide emitted from the YELP main stack shall be equal to or greater than 1:1. During the times the SO_2 CEM (which measures the inlet coker process gas from Exxon) is not operating, the minimum operating value recorded

during the past 12-months shall be used. During the times YELP's main stack SO_2 CEM is not operating, the maximum operating value recorded during the past 12-months shall be used.

2. If the initial notification from Exxon indicates Exxon has exceeded the hourly sulfur-in-fuel limit, then YELP shall continue to comply with the ratio requirement described above in paragraph K.1 until such time as YELP is notified by Exxon that the Exxon refinery has met the hourly sulfur-in-fuel limitation for 3 consecutive hourly periods.

3. If the initial notification from Exxon indicates Exxon has exceeded the daily limit on the number of barrels of fuel oil fired, then YELP shall continue to comply with the ratio requirement described above in paragraph K.1 until such time as YELP is notified by Exxon that the Exxon refinery is in compliance with the daily limit on fuel oil firing.

4. YELP shall report to the department each time it receives initial notification by Exxon as referenced above in paragraph K.1, K.2, and K.3. The report shall be submitted with the emission report to the department required in Section III, Part D. of this permit, and shall include both the date and time YELP received initial and subsequent notification by Exxon, as referenced above in paragraph K.1, K.2, and K.3, as appropriate. The report shall also describe, in detail, the operating measures taken by YELP to meet the requirements in paragraphs K.1 through K.3**.**

L. Total plant emissions for the listed pollutants shall not exceed the following (ARM 17.8.715):

1. Main Stack

   a. Sulfur Dioxide Emissions **-** 2476.0 tons/yr computed as a 12-month total at the end of each calendar-month; 8.160 tons/day, 680.0 maximum lb/hr; 620.0 lb/hr computed on a rolling 30-day average (0.777 lb/mmBTU).

   b. Nitrogen Oxides **-** 1,396.0 tons/yr; 319.0 lb/hr computed on a rolling 30-day average (0.400 lb/mmBTU).

   c. Opacity **-** 20% averaged over any 6 consecutive minutes.

   d. Particulate Matter **-** 80.0 tons/yr; 438.4 lb/day; 18.26 lb/hr (0.023 lb/mmBTU).

   e. Carbon Monoxide **-** 529.0 tons/yr; 2898.6 lb/day; 120.6 lb/hr.

   f. Minimum of 92% SO_2 control for all boiler operating hours[1]. Percent control of SO_2 shall be determined according to the provision in 40 CFR 60, Subpart Da, Section 60.48a, except that the percent control is required for all boiler operating hours instead of the boiler operating days as identified in 40 CFR 60.

2. Coke Storage Facility and Loading

   a. Particulate Matter **-** 18.1 tons/yr.

   b. Opacity **-** 20% averaged over any 6 consecutive minutes.

   c. Baghouse filter emissions shall not exceed 0.01 grains per dscf.

3. Coke Unloading/Crushing/Processing Facility and Coke Barn

1 "Boiler operating hour" means any time during a 60 minute clock hour in which a boiler operates.

a. Opacity - 20% averaged over any 6 consecutive minutes.

b. Baghouse filter emissions from the coke unloading/crushing/ processing facility shall not exceed 0.01 grains per dscf.

4. Ash Silo and Unloading

a. Opacity - 20% averaged over any six consecutive minutes.

b. Baghouse filter emissions shall not exceed 0.01 grains per dscf.

5. Limestone Unloading, Crushing, and Conveying

a. Opacity - 20% averaged over any 6 consecutive minutes.

b. Baghouse filter emissions shall not exceed 0.01 grains per dscf.

6. In addition, where applicable, all other federal emission limitations (ARM 17.8.340) shall be met, including, but not limited to, the following for the main stack:

a. SO_2 - Standard for sulfur dioxide contained in 40 CFR 60.43a.

b. NO_x - Standard for nitrogen oxides contained in 40 CFR 60.44a.

c. Particulate - Standard for particulate matter contained in 40 CFR 60.42a.

d. For purposes of ARM 17.8.340, 40 CFR, 60.40a, and this permit, the cat slurry oil shall be considered a liquid fuel. YELP is authorized to burn petroleum coke (solid fuel), coker gas (gas fuel), and cat slurry oil (liquid fuel) (ARM 17.8.710).

7. YELP may install and operate a storage tank for cat slurry oil of no greater than 30,000 gallons. The tank shall be heated using steam from the YELP facility (ARM 17.8.710).

8. YELP shall comply with the applicable requirements of 40 CFR, 60.110b, as required (ARM 17.8.340).

9. Cat slurry oil shall not be fired in the boilers until the average combustor temperature reaches 1400^{o}F (ARM 17.8.710).

M. YELP shall install and operate the following Continuous Emission Monitors/ Continuous Emission Rate Monitors (CEMs/CERMs) (ARM 17.8.340 and ARM 17.8.710):

1. Main Stack
   a. Opacity
   b. Sulfur Dioxide
   c. Nitrogen Oxides
   d. Oxygen
   e. Carbon Monoxide
   f. Volumetric Flow Rate

2. Coker Process Gas Flue

   a. Sulfur Dioxide
   b. Volumetric Flow Rate

Said monitors shall comply with all applicable provisions of 40 CFR, Parts 60.5 through 60.13, Subparts Da 60.46a through 60.49a and Appendix B, Performance Specifications 1, 2, 3, and 4.

Volumetric flow rate monitors shall comply with the requirements of Attachment 2, including Methods A-1 and B-1. Fuel oil flowmeters and fuel oil sulfur analysis shall comply with the requirements of Attachment 2, including Methods C-1 (ARM 17.8.710).

N. Compliance with emission limits in Section II.L.1, II.L.6, and II.K shall be determined by utilizing data taken from the continuous emission monitors (CEMs) listed in II.M above, and as required by 40 CFR 60, Subpart Da, and other department-approved sampling methods. Compliance with Section II.L.1.f. shall also include information gathered as required by Section III. Compliance with emission limits in Section II.L.2 through 6 shall be determined by department-approved sampling and done in accordance with the Montana Source Test Protocol and Procedures Manual. However, opacity compliance may also be determined via EPA Reference Method 9 by a certified observer or monitor. The above does not relieve YELP from meeting any applicable requirements of 40 CFR 60, Appendices A and B, or other stack testing that will be required by the department. The department shall require compliance stack testing at the YELP main stack, on a semi-annual basis for the first 2-years of operation, and annually thereafter. Testing will include, but is not limited to, the following air pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM, PM-10) and toxic air pollutants (TAPs).

Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the department. All gaseous continuous emission monitors shall be required to comply with quality assurance/quality control procedures in 40 CFR Part 60, Appendix F and the CEM availability requirements in 40 CFR 60.47a. CEM systems are to be in operation at all times when the emission units are operating except for quality assurance and control checks, breakdowns and repairs. In the event the primary CEM system is unable to meet minimum availability requirements, YELP shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated. YELP shall submit the alternative monitoring plan for department approval within 60 days after achieving the maximum production rate for the facility and not later than 180 days after initial start up (ARM 17.8.105, ARM 17.8.106, ARM 17.8.710, and ARM 17.8.340).

O. Compliance testing and continuous monitor certification shall be as specified in 40 CFR Part 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be approved by the department prior to commencement of testing. Certification of all CEMS/CERMS shall be conducted annually. The annual monitor certification can coincide with the required compliance stack testing (ARM 17.8.106 and ARM 17.8.710).

P. YELP shall conduct source testing and demonstrate compliance with the limits contained in Section II.L, except Section II.L.3, within 180 days of issuance of the permit #2650-03 and every 4-years thereafter or according to another testing schedule as may be approved by the department (ARM 17.8.105 and ARM 17.8.710).

Q. Bypassing any pollutant control device during operation except as expressly provided for in 40 CFR 60.46a and ARM 17.8.110, Malfunctions, is prohibited.

R. All access roads shall use either paving or chemical dust suppression to limit excessive fugitive dust, with water suppression as a back up measure. Construction and earth-moving activities shall use reasonable precautions for limiting excessive fugitive dust from impacting nearby residential and commercial establishments (ARM 17.8.308).

S. YELP shall not cause or authorize the discharge into the atmosphere of emissions from production, handling, or transportation which exhibit an opacity of 20% or greater (ARM 17.8.308).

SECTION III: Monitoring and Reporting

A. YELP shall install, operate and maintain the applicable CEMs/CERMs listed in Section II. M. Emission monitoring shall be subject to 40 CFR 60, Subpart Da, Appendix B (Performance Specifications 1, 2, 3, 4, and 6) and Appendix F (Quality Assurance/Quality Control) provisions. Any stack testing requirements that will be required (in Item II.N) shall be conducted according to 40 CFR 60, Appendix A and ARM 17.8.105, Testing Requirements Provisions (ARM 17.8.106 and ARM 17.8.710).

B. YELP shall analyze the weight percent sulfur and heating value (BTU/lb) of the solid petroleum coke fuel on a monthly basis when the boilers are operating. Twice per month YELP shall analyze the coker gas stream to facilitate the F-Factor determination when the boilers are operating. Analyses procedures and methods shall follow 40 CFR 60.48a, including Reference Method 19 (ARM 17.8.710, 40 CFR 60, Subpart Da, 40 CFR 60, Appendix A).

C. YELP shall install, operate, and maintain a continuous fuel oil flowmeter. YELP shall comply with the following fuel oil[2] flowmetering and analysis specifications:

1. Conduct daily fuel oil sampling in accordance with Method C-1 of Attachment 2.

2. Analyze all fuel oil samples collected, as required by Section III.C.1., for sulfur content in accordance with Method C-1 of Attachment 2.

3. Each fuel oil flowmeter shall demonstrate a flowmeter accuracy of 2.0 percent of the upper range value (i.e., maximum calibrated oil flow rate) as measured under laboratory conditions by the manufacturer or by the owner or operator, and pursuant to the calibration procedures as specified by Method C-1 of Attachment 2.

D. Beginning with the first quarter of 1998, YELP shall submit quarterly emission reports. Emission reporting for sulfur dioxide from the main stack and Exxon coker process gas shall consist of hourly and 24-hour calendar day totals for each calendar month. The reports, which are due 30 days after the end of each period, shall also include the following (ARM 17.8.710):

1. Source or unit operating time during the reporting period and daily petroleum coke fuel, daily cat slurry oil, and limestone consumption.

2. Monitoring down time which occurred during the reporting period.

3. A summary of excess emissions for each pollutant and averaging period identified in Section II.L.1.a through II.L.1.f.

4. Emission estimates for sulfur oxides and reduced sulfides from material balance, engineering calculation data, and any emission testing. Report of sulfur and BTU content from petroleum coke fuel analysis on a daily basis. Report of sulfur and BTU content from the cat slurry oil analysis on a daily basis.

5. Reasons for any emissions in excess of those specifically allowed in Section II. L.1 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

E. YELP shall keep the department apprised of the status of construction, dates of performance tests, and continuous compliance status for each emission point and pollutant. In addition to applicable requirements of 40 CFR 60.7, the following reports and recordkeeping shall be required:

1. Notification of date of cessation of construction, restarts of construction, startups, and monitor certification tests (ARM 17.8.340).

[2] "Fuel Oil" means cat slurry oil from the Exxon fluid catalytic cracking (FCC) unit.

2. Commencement of construction of the spray nozzles, pneumatic line, and tank associated with the ability to combust cat slurry oil within 15 days of commencement of construction (ARM 17.8.710).

3. Anticipated start-up date of the spray nozzles, pneumatic line, and tank associated with the ability to combust cat slurry oil between 30 and 60 days prior to anticipated start-up date (ARM 17.8.710).

4. Actual start-up date of the spray nozzles, pneumatic line, and tank associated with the ability to combust cat slurry oil within 15 days of actual start-up date (ARM 17.8.710).

5. Final design drawings for the spray nozzles within 15 days of completion of construction (ARM 17.8.710).

6. Commencement of construction of the pneumatic lines for unloading coke from trucks within 15 days of commencement of construction (ARM 17.8.710).

7. Anticipated start-up date of the pneumatic lines for unloading coke from trucks between 30 and 60 days prior to anticipated start-up date (ARM 17.8.710).

8. Actual start-up date of the pneumatic lines for unloading coke from trucks within 15 days of actual start-up date (ARM 17.8.710).

9. Commencement of construction of the Coke Unloading / Crushing / Processing facility and the Coke Barn storage and handling facility within 15 days of commencement of construction (ARM 17.8.710).

10. Anticipated start-up date of the Coke Unloading / Crushing / Processing facility and the Coke Barn storage and handling facility between 30 and 60 days prior to anticipated start-up date (ARM 17.8.710).

11. Actual start-up date of the Coke Unloading / Crushing / Processing facility and the Coke Barn storage and handling facility within 15 days of actual start-up date (ARM 17.8.710).

12. All source tests shall be conducted in compliance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

13. Copies of emissions report, excess emissions and all other such items mentioned in Section III shall be submitted to both the Billings Regional Office and the Helena office of the department (ARM 17.8.710).

14. Monitoring data shall be maintained for a minimum of 5 years at the YELP facility (ARM 17.8.710).

15. All data and records that are required to be maintained must be made available upon request by representatives of the department, the U.S. Environmental Protection Agency, and the Yellowstone County Air Pollution Control Agency (ARM 17.8.710).

F. YELP shall conduct ambient air monitoring as described in Attachment 1 (ARM 17.8.204 and ARM 17.8.822).

G. Operational Reporting Requirements

1. YELP shall supply the department with annual production information for all emission points, as required by the department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the

emission inventory contained in the permit analysis and sources identified in Section I of the permit analysis.

Production information shall be gathered on a calendar-year basis and submitted to the department by the date required in the emission inventory request. Information shall include the following, and be in units as required by the department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or verifying compliance with permit limitations (ARM 17.8.505).

a. Tons of petroleum coke consumed in the boilers.
b. Gallons of diesel consumed in the boilers.
c. Gallons of cat slurry oil consumed in the boilers.
d. Million standard cubic feet coker gas consumed in the boilers.
e. Tons of limestone received.
f. Tons of ash removed from the ash silos.
g. Tons of petroleum coke received by truck.
h. Total tons of SO_2 in the Coker Process Gas.
i. Annual average percent sulfur in the petroleum coke.
j. Annual average million BTU per pound for the petroleum coke.
k. Annual average percent sulfur in cat slurry oil.
l. Annual average million BTU per pound of cat slurry oil.
m. Total tons of petroleum coke crushed/processed in the Coke Unloading/Crushing/Processing Plant.
n. Total tons of coke stored in the Coke Barn.
o. Total tons of coke crushed/processed in the Limestone Unloading, Crushing, and Conveying facility.
p. Total tons of off-site coke transported to and stored at the Exxon Refinery coke storage area.
q. Total tons of petroleum coke processed on site (crushed, stored and handled)

2. YELP shall notify the department of any construction or improvement project conducted pursuant to ARM 17.8.705(1)(r) that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emissions unit. The notice must be submitted to the department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.705(1)(r)(iv) (ARM 17.8.705).

3. YELP shall supply the department with annual processing/storage information for off-site petroleum coke. YELP shall document, by month, the total amount of off-site coke processed/stored at the facility. By the 25 of each month, YELP shall total the monthly coke transported and dumped at the Exxon Refinery coke storage area, the total amount of coke processed in the Coke Unloading, Crushing, Processing facility, the total amount of coke processed in the Limestone Unloading, Crushing, and Conveying facility, and the total amount of coke stored in the Coke Barn during the previous 12 months to verify compliance with the limitation in Section II.H.1, II.H.2, and II.H.3. A written report of compliance verification shall be submitted along with the annual emissions inventory (ARM 17.8.710).

4. YELP shall maintain records of the date of all transfers of off-site petroleum coke to the Exxon Refinery coke storage area to demonstrate compliance with Section II.H.3 (ARM 17.8/710).

5. All records compiled in accordance with this permit must be maintained by YELP as a permanent business record for at least 5 years following the date of the measurement,

must be available at the plant site for inspection by the department and must be submitted to the department upon request (ARM 17.8.710).

SECTION IV: General Conditions

A. Inspection - YELP shall allow the department's representatives access to the source at all reasonable times for the purpose of making inspections, surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver - The permit and all the terms, conditions, and matters stated herein shall be deemed accepted if YELP fails to appeal as indicated below.

C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving the permittee of the responsibility for complying with any applicable federal or Montana statute, rule or standard, except as specifically provided in ARM 17.8.701, *et seq*. (ARM 17.8.717).

D. Enforcement - Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties or other enforcement as specified in Section 75-2-401 *et seq*., MCA.

E. Appeals - Any person or persons jointly or severally adversely affected by the department's decision may request, within 15 days after the department renders its decision, upon affidavit setting forth the grounds therefor, a hearing before the Board of Environmental Review. A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The department's decision on the application is not final unless 15 days have elapsed and there is no request for a hearing under this section. The filing of a request for a hearing postpones the effective date of the department's decision until the conclusion of the hearing and issuance of a final decision by the Board.

F. Permit Inspection - As required by ARM 17.8.716, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by department personnel at the location of the permitted source.

G. Construction Commencement - Construction must begin within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall be revoked.

H. Permit Fees - Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, the continuing validity of this permit is conditional upon the payment by the permittee of an annual operation fee, as required by that Section and rules adopted thereunder by the Board.

ATTACHMENT 1

AMBIENT MONITORING PLAN
YELLOWSTONE ENERGY LIMITED PARTNERSHIP
Permit #2650-07

1. This ambient air monitoring plan is required by air quality permit #2650-06 which applies to the petroleum coke-fired power generation facility adjacent to the Exxon petroleum refinery in Billings, Montana. This monitoring plan may be changed from time to time by the department, but all current requirements of this plan are also considered conditions of the permit.

2. Yellowstone Energy Limited Partnership (YELP) shall operate and maintain two air monitoring sites in the vicinity of their power generation facility. The exact locations of the monitoring sites must be approved by the department and meet all the requirements contained in the Montana Quality Assurance Manual, including revisions; the EPA Quality Assurance Manual, including revisions; the EPA Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), including revisions (EPA-450/4-87-007); Parts 53 and 58 of the Code of Federal Regulations; and any other requirements specified by the department.

3. YELP shall continue air monitoring for a minimum of two years after maximum production has been achieved. At that time, the air monitoring data will be reviewed and the department will determine if continued monitoring or additional monitoring is warranted. The department may require continued air monitoring to track long-term impacts of emissions from the facility or require additional ambient air monitoring if any changes take place in regard to quality and/or quantity of emissions or the area of impact from the emissions.

4. YELP shall monitor the following parameters at the sites and frequencies described below:

AIRS Number	**Site Name**	**UTM Coordinates (All Zone 12)**	**Parameter**	**Frequency**
30-111-2006	Johnson Lane	E 701010 N 5076000	SO_2[1], Wind Speed and Direction, Temperature, Sigma Theta[2]	Continuous
30-111-2007	Pine Hills	E 703670 N 5078600	SO_2, Wind Speed and Direction, Temperature, Sigma Theta	Continuous
[1] SO_2 = sulfur dioxide [2] Sigma Theta = Standard Deviation of Horizontal Wind Direction				

5. Data recovery for all parameters shall be at least 80 percent computed on a quarterly and annual basis. The department may require continued monitoring if this condition is not met.

6. Any ambient air monitoring changes proposed by YELP must be approved in writing by the department.

7. YELP shall utilize air monitoring and quality assurance procedures which are equal to or exceed the requirements described in the Montana Quality Assurance Manual, including revisions; the EPA Quality Assurance Manual, including revisions; the EPA Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), including revisions (EPA-450/4-87-007); 40 CFR Parts 53 and 58 of the Code of Federal Regulations; and any other requirements specified by the department.

8. YELP shall submit quarterly data reports within 45 days after the end of the calendar quarter and an annual data report within 90 days after the end of the calendar-year. The annual report may be substituted for the fourth quarterly report if all information in 9 below is included in the annual report.

9. The quarterly report shall consist of a narrative data summary and a data submittal of all data points in AIRS format. This data must be submitted in ASCII files on 3" or 5" high or low-density floppy disks, in IBM-compatible format, or on AIRS data entry forms. The narrative data summary shall include:

    a. A topographic map of appropriate scale, with UTM coordinates and a true north arrow, showing the air monitoring site locations in relation to the YELP facility and the general Billings area;

    b. A hard copy of the individual data points;

    c. The quarterly and monthly means for SO_2, wind speed and direction;

    d. The first and second highest hourly concentrations for SO_2;

    e. The first and second highest, rolling 3-hour concentrations for SO_2;

    f. The first and second highest, rolling 24-hour concentrations for SO_2;

    g. The quarterly and monthly wind roses;

    h. A summary of the data collection efficiency;

    i. A summary of the reasons for missing data;

    j. A precision and accuracy (audit) summary;

    k. A summary of any ambient air standard or PSD increment exceedances; and

    l. Calibration information.

10. The annual data report shall consist of a narrative data summary containing:

    a. A topographic map of appropriate scale, with UTM coordinates and a true north arrow, showing the air monitoring site locations in relation to the YELP facility and the general Billings area;

    b. A pollution trend analysis;

    c. The annual means for SO_2, wind speed and direction;

    d. The first and second highest hourly concentrations for SO_2;

    e. The first and second highest, rolling three-hour concentrations for SO_2;

    f. The first and second highest, rolling 24-hour concentrations for SO_2;

g. The annual wind rose;

h. An annual summary of data collection efficiency;

i. An annual summary of precision and accuracy (audit) data, including the results from EPA's National Performance Audit for SO_2;

j. An annual summary of any ambient standard or PSD increment exceedance; and

k. Recommendations for future monitoring.

11. The department may audit, or may require YELP to contract with an independent firm to audit the air monitoring network, the laboratory performing associated analyses, and any data handling procedures at unspecified times. On the basis of the audits and subsequent reports, the department may recommend or require changes in the air monitoring network and associated activities in order to improve precision, accuracy and data completeness.

ATTACHMENT 2

PERFORMANCE SPECIFICATIONS FOR STACK FLOW RATE MONITORS,
FUEL OIL FLOWMETERS, AND FUEL OIL SULFUR ANALYSIS
(Includes Methods A-1, B-1, & C-1)

METHOD A-1
INSTALLATION AND INITIAL CERTIFICATION
IN-STACK OR IN-DUCT FLOW MONITORS

1.0 FLOW MONITOR INSTALLATION AND MEASUREMENT LOCATION

Install the flow monitor in a location that provides representative volumetric flow for all operating conditions. Such a location provides an average velocity of the flue gas flow over the stack or duct cross section, provides a representative SO_2 emission rate (in lb/hr), and is representative of the pollutant concentration monitor location. Where the moisture content of the flue gas affects volumetric flow measurements, use the procedures in both Reference Methods 1 and 4 of 40 CFR Part 60, Appendix A, to establish a proper location for the flow monitor.

The department recommends (but does not require) performing a flow profile study following the procedures in 40 CFR Part 60, Appendix A, Test Method 1, Section 2.5 to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points required to obtain a representative flow value. The procedure in 40 CFR Part 60, Appendix A, Test Method 1, Section 2.5 may be used even if the flow measurement location is greater than or equal to two equivalent stack or duct diameters downstream or greater than or equal to ½ duct diameter upstream from a flow disturbance. If a flow profile study shows that cyclonic (or swirling) or stratified flow conditions exist at the potential flow monitor location that are likely to prevent the monitor from meeting the performance specifications of this Method, then the department recommends either (1) selecting another location where there is no cyclonic (or swirling) or stratified flow condition, or (2) eliminating the cyclonic (or swirling) or stratified flow condition by straightening the flow, e.g., by installing straightening vanes. The department also recommends selecting flow monitor locations to minimize the effects of condensation, coating, erosion, or other conditions that could adversely affect flow monitor performance.

1.1 Acceptability of Flow Monitor Location

The installation of a flow monitor is acceptable if: (1) the location satisfies the minimum siting criteria of Method 1 in Appendix A to 40 CFR Part 60 (i.e., the location is greater than or equal to eight stack or duct diameters downstream and two diameters upstream from a flow disturbance; or, if necessary, two stack or duct diameters downstream and one-half stack or duct diameter upstream from, a flow disturbance); (2) the results of a flow profile study, if performed, are acceptable (i.e., there are no cyclonic (or swirling) or stratified flow conditions); and (3) the flow monitor satisfies the performance specifications of this Method. If the flow monitor is installed in a location that does not satisfy these physical criteria, but the monitor achieves the performance specifications of this Method, then the department may certify the location as acceptable.

1.2 Alternative Flow Monitoring Location

Whenever the flow monitor is installed in a location that is greater than or equal to two stack or duct diameters downstream and greater or equal to one-half diameter upstream from a flow disturbance, and/or in a location that is acceptable based on a flow profile study, but nevertheless the monitor does not achieve the performance specifications of this Method, perform another flow profile study (the procedures described in 40 CFR Part 60, Appendix A, Method 1, Section 2.5 may be used) to select an alternative flow monitoring installation site.

Whenever the owner or operator successfully demonstrates that modifications to the exhaust duct or stack (such as installation of straightening vanes, modifications of ductwork, and the like) are necessary for the flow monitor to meet the performance specifications, the department may approve an interim alternative flow monitoring methodology and an extension to the required certification date for the flow monitor.

If no location exists that satisfies the physical siting criteria in section 1.1, where the results of flow profile studies performed at two or more alternative flow monitor locations are unacceptable, or where installation of a flow monitor in either the stack or the ducts is demonstrated to be technically infeasible, the owner or operator may petition the department for an alternative method for monitoring flow.

2.0 FLOW MONITOR EQUIPMENT SPECIFICATIONS

2.1 Instrument Span - General Requirements

In implementing Section 2.1.1 of this Method, to the extent practicable, measure at a range such that the majority of readings obtained during normal operation are between 25 and 75 percent of full-scale range of the instrument.

2.1.1 Instrument Span for Flow Monitors

Select the full-scale range of the flow monitor so it is consistent with Section 2.1 of this Method and can accurately measure all potential volumetric flow rates at the flow monitor installation site. Establish the span value of the flow monitor at a level which is approximately 80% of the full-scale range and 125% of the maximum expected flow rate. Based on the span value, establish reference values for the calibration error test in accordance with Section 2.2.1.

If the volumetric flow rate exceeds the flow monitor's ability to accurately measure and record values, adjust the full-scale range, span value, and reference values as described above and in Section 2.2.1. Record the new span value and report the new span value and reference values as parts of the results of the calibration error test required by Method B-1. Whenever the span value is adjusted, use reference values for the calibration error test based on the new span value.

2.2 Flow Monitor Design for Quality Control Testing

Design all flow monitors to meet the applicable performance specifications of this Method.

2.2.1 Flow Monitor Calibration Error Test

Design and equip each flow monitor to allow for a daily calibration error test consisting of at least two reference values: (1) Zero to 20 percent of span or an equivalent reference value (e.g., pressure pulse or electronic signal); and (2) 50 to 70 percent of span. Flow monitor response, both before and after any adjustment, must be capable of being recorded by the data acquisition and handling system. Design each flow monitor to allow a daily calibration error test of: (1) the entire flow monitoring system, from and including the probe tip (or equivalent) through and including the data acquisition and handling system; or (2) the flow monitoring system from, and including, the transducer through and including the data acquisition and handling system.

2.2.2 Flow Monitor Interference Check

Design and equip each flow monitor in a manner to minimize interference due to moisture. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver or equivalent.

Design and equip each differential pressure flow monitor to provide: (1) an automatic, periodic back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on a least a daily basis to prevent velocity sensing interference; and (2) a means for detecting leaks in the system on a least a quarterly basis (manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (e.g., backpurging system) to prevent velocity sensing interference.

3.0 FLOW MONITOR PERFORMANCE SPECIFICATIONS

3.1 Flow Monitor Calibration Error

The calibration error of flow monitors shall not exceed 3.0 percent, based upon the span of the instrument as calculated using Equation A-1 of this Method.

3.2 Flow Monitor Relative Accuracy

Except as provided in this Section, the relative accuracy for flow monitors, where volumetric gas flow is measured in scfh, shall not exceed 20.0 percent. For affected units where the average of the flow monitor measurements of gas velocity during the relative accuracy test audit is less than or equal to 10.0 fps, the mean value of the flow monitor velocity measurements shall not exceed +/- 2.0 fps of the reference method mean value in fps wherever the relative accuracy specification above is not achieved.

4.0 DATA ACQUISITION AND HANDLING SYSTEMS

Automated data acquisition and handling systems shall: (1) read and record the full range of pollutant concentrations and volumetric flow from zero through span; and (2) provide a continuous record of all measurements and required information in an electronic format specified by the department and capable of transmission via an IBM-compatible personal computer diskette or other electronic media. These systems also shall have the capability of interpreting and converting the individual output signals from a pollutant concentration monitor and a flow monitor to produce a continuous readout of pollutant mass emission rates in pounds per hour.

Data acquisition and handling systems shall also compute and record monitor calibration error.

5.0 INITIAL FLOW MONITOR CERTIFICATION TESTS AND PROCEDURES

5.1 Flow Monitor Pretest Preparation

Install the components of the continuous flow monitor as specified in Sections 1.0, 2.0, and 3.0 of this Method, and prepare each system component and the combined system for operation in accordance with the manufacturer's written instruction. Operate the unit(s) during each period when measurements are made.

5.2 7-Day Calibration Error Test for Flow Monitors

Measure the calibration error of each flow monitor according to the following procedures.

Introduce the reference signal corresponding to the values specified in Section 2.2.1 of this Method to the probe tip (or equivalent), or to the transducer. During the seven-day certification test period, conduct the calibration error test once each day while the unit is operating (as close to 24-hour intervals as practicable). Record the flow monitor responses by means of the data acquisition and handling system. Calculate the calibration error using Equation A-1 of this Method.

Do not perform any corrective maintenance, repair, replacement or manual adjustment to the flow monitor during the seven-day certification test period other than that required in the monitor operation and maintenance manual. If the flow monitor operates within the calibration error performance specification, (i.e., less than or equal to three percent error each day and requiring no corrective maintenance, repair, replacement or manual adjustment during the seven-day test period) the flow monitor passes the calibration error test portion of the certification test. Whenever automatic adjustments are made, record the magnitude of the adjustments. Record all maintenance and required adjustments. Record output readings from the data acquisition and handling system before and after all adjustments.

5.3 Flow Monitor Relative Accuracy

Within 90 days of installation, concurrent relative accuracy test audits may be performed by conducting simultaneous SO_2 concentration and volumetric flow relative accuracy test audit runs, or by alternating an SO_2 relative accuracy test audit run with a flow relative accuracy test audit run until all relative accuracy test audit runs are completed. Where two or more probes are in the same proximity, care should be taken to prevent probes from interfering with each other's sampling. For each SO_2 pollutant concentration monitor and each flow monitor, calculate the relative accuracy with data from the relative accuracy test audits.

Perform relative accuracy test audits for each flow monitor at normal operating load expressed in terms of percent of flow monitor span. If a flow monitor fails the relative accuracy test, the relative accuracy test audit must be repeated.

Complete each relative accuracy test audit within a seven-day period while the unit is operating in a normal condition. Do not perform corrective maintenance, repairs, replacements or adjustments during the relative accuracy test audit other than as required in the operation and maintenance manual.

5.3.1 Calculations

Using the data from the relative accuracy test audits, calculate relative accuracy in accordance with the procedure and equations specified in Section 6 of this Method.

5.3.2 Reference Method Measurement Location

Select a location for reference method measurements that is: (1) accessible; (2) in the same proximity as the monitor or monitoring system location; and (3) meets the requirements of Method 1 (or 1A) of 40 CFR Part 60, Appendix A for volumetric flow, except as otherwise indicated in this Section.

5.3.3 Reference Method Traverse Point Selection

Select traverse points that: (1) ensure acquisition of representative samples of pollutant concentration, moisture content, temperature, and flue gas flow rate over the flue cross section; and (2) meet the requirements of Method 1 (or 1A) (for volumetric flow), and Method 4 (for moisture determination) in 40 CFR part 60, Appendix A.

5.3.4 Sampling Strategy

Conduct the reference method tests so they will yield results representative of the moisture content, temperature, and flue gas flow rate from the unit and can be correlated with the flow monitor measurements. Conduct any moisture measurements that may be needed simultaneously with the flue gas flow rate measurements. To properly correlate volumetric flow rate data with the reference method data, mark the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s).

5.3.5 Correlation of Reference Method and Continuous Emission Monitoring System

Confirm that the monitor or monitoring system and reference method test results are on consistent moisture, pressure, and temperature basis (e.g., since the flow monitor measures flow rate on a wet basis, Method 2 test results must also be on a wet basis). Compare flow-monitor and reference method results on a scfh basis. Also consider the response time of the flow monitoring system to ensure comparison of simultaneous measurements. For each relative accuracy test audit run, compare the measurements obtained from the flow monitor against the corresponding reference method values. Tabulate the paired data in a table similar to the one shown in Figure 1.

5.3.6 Number of Reference Method Tests

Perform a minimum of nine sets of paired monitor (or monitoring system) and reference method test data for every required relative accuracy test audit. Conduct each set within a period of 30 to 60 minutes.

The tester may choose to perform more than nine sets of reference method tests. If this option is chosen, the tester may reject a maximum of three sets of the test results as long as the total number of test results used to determine the relative accuracy is greater than or equal to nine. Report all data, including the rejected data, and reference method test results.

5.3.7 Reference Methods

The following methods from 40 CFR, Part 60, Appendix A or their approved alternatives are the reference methods for performing relative accuracy test audits: Method 1 or 1A for siting; Method 2 (or 2A, 2C, or 2D as appropriate) for velocity; and Method 4 for moisture.

6.0 CALCULATIONS

6.1 Flow Monitor Calibration Error (Drift)

For each reference value, calculate the percentage calibration error based upon span using the following equation:

(EQ.A-1)

$$CE = \frac{(R - A)}{S} x\, 100$$

Where:

CE = Calibration error;
R = Low or high level reference value specified in Section 2.2.1 of this Method;
A = Actual flow monitor response to the reference value; and
S = Flow monitor span.

Whenever the flow rate exceeds the monitor's ability to measure and record values accurately, adjust the span to prevent future exceedances. If process parameters change or other alterations are made so the expected flue gas velocity may change significantly, adjust the span to assure the continued accuracy of the monitoring system.

6.2 Relative Accuracy for Flow Monitors

Analyze the relative accuracy test audit data from the reference method tests for flow monitors using the following procedures. Summarize the results on a data sheet. An example is shown in Figure 1. Calculate the mean of the monitor or monitoring system measurement values. Calculate the mean of the reference method values. Using data from the automated data acquisition and handling system, calculate the arithmetic differences between the reference method and monitor measurement data sets. Then calculate the arithmetic mean of the difference, the standard deviation, the confidence coefficient, and the monitor or monitoring system relative accuracy using the following procedures and equations.

6.2.1 Arithmetic Mean

Calculate the arithmetic mean of the differences, $\bar{d}$, of a data set as follows.

(Eq. A-2)

$$\bar{d} = \frac{1}{n} \sum_{i=1}^{n} d_i$$

Where:

n=Number of data points

$\sum_{i=1}^{n} d_i$ = Algebraic sum of the individual differences d_i

d_i = The difference between a reference method value and the corresponding continuous flowrate monitoring system value (RM_i-FR_i) at a given point in time i.

When calculating the arithmetic mean of the difference of a flow monitor data set, be sure to correct the monitor measurements for moisture if applicable.

6.2.2 Standard Deviation

Calculate the standard deviation, S_d of a data set as follows:

(Eq. A-3)

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n}\right]}{n-1}}$$

6.2.3 Confidence Coefficient

Calculate the confidence coefficient (one-tailed), cc, of a data set as follows.

(Eq. A-4)

$$CC = t_{0.025} \frac{S_d}{\sqrt{n}}$$

where:

$t_{0.025}$ = t value (see Table 2)

TABLE 2 T-VALUES

n-1	**$t_{0.025}$**	**n-1**	**$t_{0.025}$**	**n-1**	**$t_{0.025}$**
1…….	12.706	12	2.179	23	2.069
2.......	4.303	13	2.160	24	2.064
3.......	3.182	14	2.145	25	2.060
4.......	2.776	15	2.131	26	2.056
5.......	2.571	16	2.120	27	2.052
6.......	2.447	17	2.110	28	2.048
7.......	2.365	18	2.101	29	2.045
8.......	2.306	19	2.093	30	2.042
9.......	2.262	20	2.086	40	2.021
10......	2.228	21	2.080	60	2.000
11......	2.201	22	2.074	>60	1.960

6.2.4 Relative Accuracy

Calculate the relative accuracy of a data set using the following equation.

(Eq. A-5)

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} x\, 100$$

where:

RM = Arithmetic means of the reference method values.

ξ d ξ= The absolute value of the mean difference between the reference method values and the corresponding continuous flow monitor values.

ξ cc ξ= The absolute value of the confidence coefficient.

FIGURE 1.-RELATIVE ACCURACY DETERMINATION (FLOW MONITORS)

Run No.	Date & Time	Flow rate (Normal) (scf/hr)*		
		RM	M	Diff
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
Mean or mean of differences				
		Confidence coefficient		
		Relative accuracy		

* Make sure RM and M are on a consistent moisture basis.

METHOD B-1

ON-GOING QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES
FOR IN-STACK AND IN-DUCT FLOW MONITORS

1.0 FREQUENCY OF FLOW MONITOR TESTING

A summary chart showing each quality assurance test and the frequency at which each test is required is located at the end of this Method in Table 1.

1.1 Daily Flow Monitor Assessments

For each flow monitor, perform the following assessments during each day in which the unit is operating. These requirements are effective as of the date when the monitor or continuous emission monitoring system completes certification testing.

1.1.1 Calibration Error Test for Flow Monitors

Test, compute, and record the calibration error of each flow monitor at least once on each operating day. Introduce the reference values (specified in section 2.2.1 of Method A-1) to the probe tip (or equivalent) or to the transducer. Record flow monitor output from the data acquisition and handling system before and after any adjustments to the flow monitor. Keep a record of all maintenance and adjustments. Calculate the calibration error using Equation A-1 in Method A-1.

1.1.2 Flow Monitor Interference Check

Perform the daily flow monitor interference checks specified in section 2.2.2 of Method A-1 at least once per operating day (when the unit(s) operate for any part of the day).

1.1.3 Flow Monitor Re-calibration

Adjust the calibration, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification for the flow monitor in Method A-1. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective.

1.1.4 Flow Monitor Out-of-Control Period

An out-of-control period occurs when either the low or high level reference value calibration error exceeds 6.0 percent based on the span value for five consecutive daily periods or 12.0 percent for any daily period. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out of control if two or more complete and valid readings are obtained during that hour. An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of completion of the failed interference check and ends with the hour of completion of an interference check that is passed. During any period the flow monitor is out of control, the data may not be used in calculating emission compliance nor be counted towards meeting minimum data recovery requirements.

1.1.5 Flow Monitor Data Recording

Record and tabulate all calibration error test data according to month, day, clock hour, and magnitude in scfh. Program monitors that automatically adjust data to the corrected calibration values (e.g., microprocessor control) to record either: (1) The unadjusted flow rate measured in the calibration error test prior to resetting the calibration; or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage; and (2) malfunction of each RTD, transceiver, or equivalent.

1.2 Quarterly Flow Monitor Assessments

For each flow monitor, conduct a quarterly stack velocity and flow rate check by performing a velocity traverse and visual inspection of the pitot tubes. Perform the following assessments during each calendar quarter in which the unit operates. This requirement is effective as of the calendar quarter following the calendar quarter in which the flow monitor is provisionally certified.

1.2.1 Flow Monitor Leak Check

For differential pressure flow monitors, perform a leak check of all sample lines (a manual check is acceptable) at least once during each unit operating quarter. Conduct the leak checks no less than two months apart.

1.2.2 Flow Monitor Flow Rate Check

Once during each operating quarter, and for each flow monitor, perform a flow rate check by completing a single velocity traverse, calculating the associated average flow rate, and comparing the average flow with the concurrent flow measured by the continuous flow monitor. The flow rate check shall be performed at normal operating rates or load level. The flow rate check shall be performed in accordance with Section 5.3 of Method A-1 as appropriate for a single traverse. The difference (PD) between the average flow rate determined by the single velocity traverse and the continuous flow monitor shall not exceed 20 percent as determined by equation B-1. If the single velocity traverse fails to meet the 20% difference specification, the owner/operator may conduct an additional single velocity traverse or a complete Relative Accuracy Test Audit (RATA) in accordance with Section 5.3 of Method A-1 in order to demonstrate compliance with the 20% difference or 20% relative accuracy requirements.

$$PD = \frac{TF - FR}{TF} \times 100 \qquad \text{(Eq. B-1)}$$

Where:

PD = Percent Difference;
TF = Traverse Flow (scfh);
FR = Continuous Flow Monitor Flow (scfh); and
TF and FR are on a consistent moisture basis.

If the Relative Accuracy of the latest annual Relative Accuracy Test Audit (RATA) conducted pursuant to Section 1.3.1 is less than 10%, the single velocity traverse flow rate check may be discontinued. However, if future RATAs indicate a Relative Accuracy of 10% or greater, performance of the single velocity traverse flow rate check shall resume.

1.2.3 Flow Monitor Out-of-Control Period

An out-of-control period occurs when a flow monitor fails the quarterly flow rate check (the difference between the average flow rate determined by the velocity traverse and the continuous flow monitor exceeds 20%), the visual inspection of the pitot tube indicates pluggage or wear, or if a sample line leak is detected. The out-of-control period begins with the hour of the failed flow rate check, visual inspection, or leak check and ends with the hour of a satisfactory flow rate check, RATA, leak check, or cleaning or replacement of the pitot tube. During any period that the flow monitor is out of control, the data may not be used in calculating emission compliance nor be counted towards meeting minimum data recovery requirements.

1.3 Annual Flow Monitor Assessments

For each flow monitor, perform the following assessments once annually. This requirement is effective as of the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified.

1.3.1 Flow Monitor Relative Accuracy Test Audit

For flow monitors, relative accuracy test audits shall be performed annually. The relative accuracy audit shall be performed at the normal operating rate or load level (with a minimum of nine paired velocity traverses). The relative accuracy test audit shall be conducted according to the procedures and specifications of Method A-1.

1.3.2 Flow Monitor Out-of-Control Period

An out-of-control period occurs under any of the following conditions: (1) the relative accuracy of a flow monitor exceeds 20.0 percent; or (2) for low flow situations (≤10.0 fps), the flow monitor mean value (if applicable) exceeds +/- 2.0 fps of the reference method mean whenever the relative accuracy is greater than 20.0 percent. For flow relative accuracy test audits, the out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit. During any period the flow monitor is out of control, the data may not be used in calculating emission compliance nor be counted towards meeting minimum data recovery requirements.

TABLE 1 - FLOW MONITOR QUALITY ASSURANCE TEST REQUIREMENTS

Test	QA test frequency requirements		
	Daily	**Quarterly**	**Annual**
Calibration Error (2 pt.)	X		
Interference (flow)	X		
Visual probe check		X	
Flow rate check (single traverse)		X[1]	
Leak (flow)		X[2]	
RATA (flow)			X

[1] The owner/operator has an option to perform a RATA if the quarterly flow rate check (single traverse) fails specifications. In addition, if the Relative Accuracy determined by the latest RATA is less than 10%, the quarterly single velocity traverse flow rate check may be discontinued. However, if future RATAs indicate a Relative Accuracy of 10% or greater, performance of the quarterly single velocity traverse flow rate check shall resume.

[2] The leak check requirement only applies to differential pressure flow rate monitors and does not apply to thermal or ultrasonic flow rate monitors.

METHOD C-1

FUEL OIL FLOWMETERING AND ANALYSIS SPECIFICATIONS

1.0 FLOWMETER SPECIFICATIONS

YELP shall measure and record the fuel oil consumption rate within the fuel oil loop on an hourly basis. YELP shall measure the flow of fuel oil with in-line fuel oil flowmeters, as required by Section III.C. of this permit.

1.1 Initial Calibration and Certification

Design and equip each fuel oil flowmeter used to demonstrate a flowmeter accuracy of 2.0 percent of the upper range value (i.e., maximum calibrated oil flow rate) as measured under laboratory conditions by the manufacturer or by the owner or operator. Use the procedures in the following ASME codes for flow measurement for use in the laboratory, as appropriate to the type of flowmeter: ASME MFC-3M-1989 with September 1990 Errata (Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi), ASME MFC-5M-1985 (Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters), ASME MFC-6M-1987 with June 1987 Errata (Measurement of Fluid Flow in Pipes Using Vortex Flow Meters), or ASME MFC-9M-1988 with December 1989 Errata (Measurement of Liquid Flow in Closed Conduits by Weighing Method) for all other flowmeter types. More current ASME or NIST (National Institute of Standards and Technology) procedures or other ASME or NIST procedures that are appropriate to flowmeter construction may, upon Department approval, be substituted. If the flowmeter accuracy exceeds two percent of the upper range value, the flowmeter does not qualify for certification.

1. Annual Calibration

Recalibrate each fuel oil flowmeter to a flowmeter accuracy of 2.0 percent of the upper range value at least annually, or more frequently if required by manufacturer specifications, using the same ASME procedures required for initial calibration and certification.

1.2.1 Alternative Annual Calibration Method

Alternatively, the fuel oil flowmeter may be recalibrated to a flowmeter accuracy of 2.0 percent of the upper range value at least annually by comparing the measured flow of a flowmeter to the measured flow from another flowmeter which has been calibrated or recalibrated during the previous 365 days using the procedures in ASME MFC-9M-1988 with December 1989 Errata, "Measurement of Liquid Flow in Closed Conduits by Weighing Method", or which has been recalibrated by the manufacturer. Perform the comparison over a period of no more than seven consecutive facility operating days. Compare the average of three fuel oil flow readings for each meter at three different flow levels: (1) a frequently used low operating level selected within the range between the minimum safe and stable operating level and 50% of maximum operating level; (2) a frequently used high operating level selected within the range between 80% of maximum operating level and maximum operating level; and (3) normal operating level. Calculate the flowmeter accuracy using the following equation:

$$ACC = \frac{\xi\, R - A\, \xi}{URV} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

ACC = Flow meter accuracy as a percentage of the upper range value.
R = Average of the three low-, mid-, or high-level flow measurements of the reference flowmeter.
A = Average of the three measurements of the flowmeter being tested.
URV = Upper range value of fuel flowmeter being tested (i.e. maximum measurable flow).

If the flowmeter accuracy exceeds 2% of the upper range value, either recalibrate the flowmeter until the accuracy is within the performance specification, or replace the flowmeter with another one that is within the performance specification.

2.0 FUEL OIL SAMPLING AND ANALYSIS

YELP shall perform sampling and analysis of as-fired fuel oil from the fuel oil loop to determine the percentage of sulfur by weight in the fuel oil.

2.1 Sampling Frequency and Methods

YELP shall perform daily fuel oil sampling using either the flow proportional method described in Section 2.2 or the daily manual method described in Section 2.3.

2.2 Flow Proportional Sampling Method

YELP shall conduct flow proportional fuel oil sampling or continuous drip fuel oil sampling in accordance with ASTM D4177-82 (Reapproved 1990), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products", every day the facility is combusting fuel oil within the fuel oil loop. Extract fuel oil at least once every hour and blend into a daily composite sample. The sample compositing period may not exceed 24 hours.

2.3 Daily Manual Sampling Method

Representative as-fired fuel oil samples may be taken manually every 24 hours according to ASTM D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products", provided that the highest fuel oil sulfur content recorded at that facility from the most recent 30-daily samples is used for the purposes of calculating SO_2 emissions.

2.4 Sample Archiving

Split and label each daily fuel oil sample. Maintain a portion (at least 200 cc) of each daily sample for not less than 150 calendar days after the submittal to the department of the quarterly data report for the calendar quarter during which the sample was collected. Analyze fuel oil samples for percent sulfur content by weight in accordance with ASTM D129-91, "Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)," ASTM D1552-90, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)," ASTM D2622-92, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry," or ASTM D4294-90, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy".

3.0 VOLUMETRIC FLOW MEASUREMENT

3.1 Fuel Oil Density

Where the flowmeter records volumetric flow rather than mass flow, analyze daily fuel oil samples to determine the density or specific gravity of the fuel oil (not required where the flowmeter records mass flow). Determine the density or specific gravity of the fuel oil sample in accordance with ASTM D941-88, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer," ASTM D1217-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer;" ASTM D1481-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary;" ASTM D1480-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer;" ASTM D1298-85 (Re-approved 1990), "Standard Practice for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method;" or ASTM D4052-91, "Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter".

3.2 Calculation of Mass Flow from Volumetric Flow

Where the flowmeter records volumetric flow rather than mass flow, calculate and record the fuel oil mass for each hourly period using hourly fuel oil flow measurements and the density or specific gravity of the daily oil sample.

Convert density, specific gravity, or API gravity of the fuel oil sample to density of the fuel oil sample at the sampling location's temperature using ASTM D1250-80 (Re-approved 1990), "Standard Guide for Petroleum Measurement Tables".

Where density of the fuel oil is determined by the applicable ASTM procedures from Section 3.1 of Department Method C-1, use the following equation to calculate the mass of fuel oil consumed (in lb/hr).

$$Moil = Voil \times Doil \qquad \text{(Eq. C-2)}$$

Where:

Moil = Mass of oil consumed per hr, lb/hr.
Voil = Volume of oil consumed per hr, measured in scf, gal, barrels, or m^3.
Doil = Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m^3.

PERMIT ANALYSIS
YELLOWSTONE ENERGY LIMITED PARTNERSHIP
PERMIT #2650-07

I. Process Description/Permit History

A. Process Description

The Yellowstone Energy Limited Partnership (YELP) plant location is due east of the Exxon Tank Farm, on the south side of the railroad mainline and directly south of the Exxon Refinery and Montana Sulphur & Chemical Company facilities in Billings, Montana. The legal description is the NE of Section 25, Township 1 North, Range 26 East, Yellowstone County, Montana.

The Yellowstone Power Plant is a petroleum/coke-fired co-generation facility providing both electrical power and steam. The electricity is sold to Montana Power Company and the steam is sent to Exxon. The facility is also designed to burn the coker unit process gas from the Exxon facility.

The design of the facility is for 65.0 gross megawatts and 140,000 lbs/hour of steam. The single turbine have been designed to produce a minimum of 65.0 gross megawatts and a maximum, that is probably in the range of 68.0 gross megawatts. The parasitic load will vary from 3 to 7 megawatts; therefore, the expected net megawatt output will range from 58 to 65 megawatts. YELP will have the capability of sending approximately 300,000 lb/hour of steam to the Exxon refinery. If this amount of steam is sent to Exxon, the megawatt rate will be decreased.

The facility consists of two Tampella Power circulating fluidized bed (CFB) boilers with 15,534 square feet of superheater heat surface area each, and 8,837 square feet of water wall heat surface area, each built in 1994. The nominal rating is 911 x 10^6 BTU/hr (boiler capacity combined). The maximum operating rate for both boilers combined is theoretically as high as 1,300 x 10^6 BTU/hr on a short-term basis. The CFB boilers use limestone to control the SO_2 emissions.

The CFB boilers will combust fuel in a series of circulating beds of limestone aggregate, which is fluidized by the upward flow of combustion air and the gaseous products of combustion. Primary combustion air and coker process gas are introduced at the bottom of each combustor. Each boiler is designed to fire 14.5 tons per hour of fluid petroleum coke plus the coker process gas. The boilers may fire up to 86.5 tons of fluid petroleum coke per hour, but it is expected the design of the plant and emission limits would prevent this from occurring on a regular basis. This higher rate could also only occur if the BTU value and the sulfur content of the petroleum coke were much lower than the expected average. If one CFB boiler is down, the other operating CFB combustor can accept and fire the coker process gas. This twin-system design enhances the on-stream capability and operational reliability of the plant to accept and treat the Exxon coker CO process gas stream.

Flue gases from the CFB combustors are recycled by cyclone collectors, which return the collected material to the fluidized bed level. Secondary combustion air is introduced at levels above the fluidized bed to ensure complete combustion. Sulfur and nitrogen oxides (SOx, NOx) emissions are controlled via the combustion process. Calcium carbonate (limestone), which is added to the CFB combustors, acts as a sorbent of SOx while atmospheric CFB boiler design limits NOx. The combusted flue gases also contain particulates, that are filtered or scrubbed in a high efficiency baghouse before venting to the plant stack.

The YELP facility also contains equipment for receiving petroleum coke from Exxon, Exxon coker gas, and limestone; crushing of coke; crushing of limestone; storage of off-site coke; storage of ash; and removal and transportation of ash from the boilers.

B. This permit covers the following equipment at the facility:

1. 2 circulating fluidized bed combustion boilers and cyclonic separators;
2. Steam turbine (1);
3. Electrical generator (1);
4. Petroleum coke handling system - coke hopper, pneumatic conveyors and surge bin with associated baghouse particulate control;
5. Coker process gas pneumatic duct system;
6. Limestone handling systems - truck dump, crushing, conveying storage silo, and associated baghouse particulate control (2);
7. 2 main baghouses venting through one (1) stack;
8. Ash handling system - storage silo, conveyors, and load-out;
9. 199.0 foot stack (1);
10. Air-cooled condensing unit (1);
11. Pneumatic conveyor for unloading trucks containing petroleum coke into the coke handling system;
12. Pneumatic conveyor for transferring petroleum coke from the existing limestone handling system to the petroleum coke storage silos;
13. Cat slurry oil pipeline from Exxon; and
14. Cat slurry oil tank - approximately 14,000-gallon capacity.
15. Petroleum coke unloading/crushing/processing plant and associated baghouse.
16. Coke barn – crushed/processed petroleum coke storage and handling.

C. Permit History (Detailed explanations of the permit changes are contained in the analysis of each respective permit)

The PSD permit **#2650** was issued December 13, 1991, for the construction of an electrical power generating and steam co-generation facility. The application was originally submitted on July 6, 1990. Because the facility was considered a major source, the application was subject to New Source Review and the requirements of the Prevention of Significant Deterioration (PSD) program. Billings Generation Inc. (BGI) was the application submittee, with Bison Engineering Inc. as the environmental consultants performing the air quality permitting analyses. The application was deemed complete on November 8, 1991, contingent upon acceptable modifications to existing Exxon Refinery permits because offsets of SO_2 emissions from the Exxon facility were required before construction of the BGI facility could be authorized.

The proposed petroleum coke-fired power plant originally had a nameplate rating of 49.5 megawatts and would produce approximately 42 net megawatts of electrical power generation. Gaseous emissions and particulates from the Exxon coker process unit would also be fired in the BGI combustors. The BGI power plant provides co-generated steam energy for the Exxon Refinery.

The proposal included construction of the BGI facility and some modifications at the Exxon Refinery coker-CO boiler. The modifications to the existing coker-CO boiler included the installation of flue gas duct work to divert the coker unit process gas to the BGI facility. Fluid coke, also produced by that unit, will be pneumatically fed to the BGI facility. Steam pipelines between BGI and Exxon facilities are also required.

An air cooled condenser (ACC), along with a service cooling water-cooling tower, is used by the BGI power plant. Water resource demand at the plant is minor with an ACC system. Potable water requirements, as well as service cooling water, are available from the local water users association.

An additional 99 tons per year of SO_2 emission reduction may be realized from the Exxon Refinery. The source of this reduction at the refinery will come from high-sulfur fuel oil burning. The annual SO_2 offset or net SO_2 reduction that can be expected from this overall project is 238 tons (BGI and Exxon coker gas).

Listed below is the summary of the net emission rates for the BGI facility and proposed emission changes at the Exxon Refinery:

Source	SO_2	NO_x	CO	PM	PM-10	VOC	TAPs
BGI Main Stack	2476	1396	529	80.0		11.2	
Coke Handling				12.8	5.3		
Ash Handling				1.1			X
Limestone Handling				0.9			
Exxon Coker Process Gas	-2714*						
Exxon Coker CO-Boiler	0						
Exxon Refinery Fuel Oil Burning	[-99**]						
Total	-238	1396	529	94.8	5.3	11.2	

<u>NOTES</u>:
TAP = Toxic Air Pollutants
* Average of 1988 - 1990 Years
[**] Expected, but not committed from hourly sulfur-in-fuel limitation - these offsets were modified by Permit #2650-02 and are now enforceable.
Emission decreases of NO_x, CO, and PM/PM-10 are not quantified by federally enforceable emission limitations or conditions at the Exxon Refinery. However, emissions increases at BGI, from the decreases at Exxon, have been accounted for at the (BGI) main stack.

PSD Minor Source Baseline Date **-** As a result of this first PSD application for the Billings area, the minor source baseline date is now triggered for particulates, SO_2, and NO_x. The PSD application was deemed complete on November 8, 1991.

Permit **#2650-01** was issued March 11, 1992. Billings Generation Inc. (BGI) requested a modification to permit #2650 to support SO_2 emission reductions in conjunction with the EXXON refinery and permit modification #1564-03. The modified BGI permit addressed EPA concerns in the original permit (#2650). The request was addressed under the provisions of Subchapter 11, ARM 16.8.1113(1)(b). The changes addressed verification of required offsets from the Exxon facility, contingency measures if the offsets are not met and additional modeling performed to verify that the project would not cause significant impacts to the NAAQS.

The overall SO_2 offset for the proposed project is now as follows:

BGI Main Stack	2476 tpy
Exxon Coker process gas	- 2714 tpy
Exxon Refinery Fuel Oil Burning	- 100 tpy
TOTAL	- 338 tpy

No other air pollutant emission rates are affected by this permit modification action.

Permit modification **#2650-02** was issued March 25, 1993, to change the design of the facility from one main baghouse controlling the boilers exhausting through two stacks to two baghouses exhausting through one stack.

Permit Alteration **#2650-03** was issued on December 23, 1995, to accomplish the following:

1. The permittee was changed from BGI to YELP. The plant name is to be the Yellowstone Power Plant and will be operated by Rosebud Operating Services, Inc. (ROSI).

2. The alteration also allows YELP to burn other petroleum cokes and cat slurry oil in the boilers as alternative fuels. The permit application does not contain a request for an increase in emissions.

3. Changes were made to the permit to make it consistent with the stipulation signed by YELP for its facility in Billings. The stipulation was required as part of the Billings SIP for SO_2 emissions to ensure the allowable emission rates for the facility were capped. The changes included converting the monthly reporting requirements to quarterly and modifying the flow rate monitors.

4. YELP also requested the description of the facility be changed to include a description of the current design. The original facility was designed to produce steam and use a portion of the steam to drive the parasitic load in the plant. With this permit application, YELP has identified that the load in the plant will no longer be driven by steam. The equipment in the plant will be driven by electricity. Based on this change, YELP has presented that the efficiency of the facility will be increased.

5. The department removed the lb/mmBTU requirements from some of the limits contained in Section II.I. Some lb/mmBTU values are still needed to ensure compliance with applicable requirements and to identify the possible changes in the boiler operating rate. The department also clarified the requirements of Section II.I.5. to identify the requirement references more clearly.

6. The department has removed the requirement by limiting the sulfur content of the petroleum coke. It is YELP's responsibility to ensure, regardless of the sulfur content of the fuel, the 92% control efficiency is met and the SO_2 emission limits are met.

Permit modification **#2650-04** was issued on May 18, 1996. The permit modification changed the coke sampling and analysis requirements for the facility. Previously, YELP had been required to sample the coke supply to the boilers on a daily basis for sulfur content and heating value. YELP has shown, by this sampling, that there is little variability in the sulfur content of the coke and the department has agreed that weekly sampling will be sufficient to demonstrate compliance with applicable requirements. This modification will not result in an increase in the emissions of any pollutant from the facility. Permit #2650-04 replaced Permit #2650-03.

On November 3, 1999, YELP submitted a complete permit application to alter permit #2650-04. The permit alteration involved the addition of an enclosed petroleum coke unloading/crushing/processing plant and a processed petroleum coke storage and handling building (Coke Barn) to the existing permitted equipment. Further, YELP requested an extension of time, under the general permit conditions, to install the Cat Slurry oil tank. Permit **#2650-05** replaced permit #2650-04.

On January 12, 2000, the department issued permit #2650-05; however, permit #2650-05 contained referencing errors which needed to be corrected prior to issuance of the Title V operating permit for the YELP facility. Therefore, the department issued a modification to permit #2650-05 to correct improper referencing. Permit **#2650-06** replaced permit #2650-05.

D. Current Permit Action

On June 9, 2000, the Department of Environmental Quality (department) received, from YELP, a request to modify permit #2650-06. The permit modification request involved changing the solid petroleum coke sampling frequency (sulfur and heat content) from once per week to once per month.

Because YELP has demonstrated to the department's satisfaction that monthly sampling will be adequate for solid petroleum coke sampling and in accordance with ARM 17.8.733, the department has modified permit condition III.B. However, to facilitate the F-Factor determination (40 CFR 60, Method 19), the department will require coker gas sampling twice per month as indicated in Section III.B.

Further, on October 2, 2000, the department received another modification request from YELP. The second modification request involves changing permit conditions to allow for the processing (crushing, handling, and storage) of petroleum coke in the Limestone Unloading, Crushing, and Conveying Facility. Under permit #2650-05, YELP was permitted to crush, handle, and store up to 240,900 tons/yr of petroleum coke in a yet to be constructed on-site Coke Unloading, Crushing, Processing, and Coke Barn Storage Facility. The petroleum coke processing limit of 240,900 tons/yr, as previously discussed, was established to limit potential particulate emissions from the Coke Unloading, Crushing, Processing, and Coke Barn Storage Facility to a level less than the New Source Review Prevention of Significant Deterioration (NSR/PSD) program significance level for total PM and PM_{10}. The analysis conducted to establish the limit considered several factors including baghouse control and indoor processing.

Because the existing Limestone Unloading, Crushing, and Conveying Facility incorporates the same control options as the Coke Unloading, Crushing, Processing, and Coke Barn Storage Facility, the department has determined that processing a maximum combined total of 240,900 tons of petroleum coke per year in the Limestone Unloading, Crushing, and Conveying Facility and/or the Coke Unloading, Crushing, Processing, and Coke Barn Storage Facility will not increase potential PM_{10} emissions and the request can be accomplished under ARM 17.8.705(1)(r).

Finally, on February 12, 2001, the department received an additional modification request. This request involved dumping up to 35,000 tons of coke, to be used in YELP operations, at the existing Exxon Refinery petroleum coke pile.

The department considers this modification request to be part of the same activity permitted under permit #2650-05. As previously discussed, the coke processing limit applied to the facility under permit #2650-05 was established to keep YELP out of an NSR/PSD permitting action by limiting coke processing such that potential total PM and PM_{10} emissions would be less than NSR/PSD significance. Because this permit modification request is considered part of the same activity, and because additive potential emissions would increase total project emissions to a level greater than the NSR/PSD permitting threshold for total PM and PM_{10}, YELP would be required to go through an NSR/PSD permitting action. However, because YELP still preferred to stay out of NSR/PSD review for the current permit action, the department has placed additional permit conditions which, in connection with those conditions established in permit #2650-05, will limit potential emissions to a level less than NSR/PSD significance and thus NSR/PSD review is not required for the current permit action. Permit **#2650-07** will replace permit #2650-06.

E. Additional Information

Additional information, such as applicable rules and regulations, best available control technology (BACT) and reasonably available control technology (RACT) determinations, air quality impacts, and environmental assessments, are included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial quotations of some applicable rules and regulations which apply to the facility. The complete rules are stated in the Administrative Rules of Montana (ARM) and are available upon request from the department. Upon request, the department will provide references for locations of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Sub-Chapter 1, General Provisions, including, but not limited to:

1. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the department, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the department.

2. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   YELP shall comply with all requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the department upon request.

3. ARM 17.8.110, Malfunctions. (2) The department must be notified promptly, by telephone, whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours.

4. ARM 17.8.111 Circumvention. No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant which would otherwise violate an air pollution control regulation. No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

B. ARM 17.8, Sub-Chapter 2, Ambient Air Quality, including, but not limited to:

1. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide,
2. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide,
3. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide,
4. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate,
5. ARM 17.8.223 Ambient Air Quality Standard for PM-10.

YELP must comply with the applicable ambient air quality standards. Reference Section IV, Air Quality Impacts.

C. ARM 17.8, Sub-Chapter 3, Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged to an outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter Airborne. Under this section, YELP shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.340 Standard of Performance for New Stationary Sources. The owner or operator of any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the standards and provisions of 40 CFR Part 60.

   YELP will be constructing and operating a coke crushing, processing, storage, and handling facility. Because the equipment to be added to YELP's existing permitted equipment does not meet the definition of a non-metalic mineral crushing plant, or any other applicable NSPS source, the new coke crushing, processing, storage and handling plant is not subject to NSPS requirements (40 CFR Part 60, Subpart A, General Provisions, and Subpart OOO Non-Metallic Mineral Processing Plants).

   The boilers at YELP's facility are subject to Subpart Da-Standards of Performance for Electric Utility Steam Generating Units for which Construction is commenced after September 18, 1978. The subpart contains standards for particulate, SO_2 and NO_x.

   The cat slurry oil storage tank may also be subject to 40 CFR 60 Subpart Kb if the storage tank is constructed, reconstructed, or modified after July 23, 1984. At the time of the application, the tank had not been ordered or purchased. It is assumed the tank will be a new tank (approximately 14,000 gallons and approximately 53 m^3), which is greater than the capacity contained in Subpart Kb for applicability. Based on the size, the applicable requirements appear to be 60.116b(b).

D. ARM 17.8, Sub-Chapter 5, Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. YELP shall submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the department. The current permit action is considered an administrative permit action and does not require an application fee.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the department by each source of air contaminants holding an air quality permit, excluding an open burning permit, issued by the department. This operation fee is based on the actual or estimated amount of air pollutants emitted during the previous calendar- year.

An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, as described above, shall take place on a calendar-year basis. The department may insert into any final permit issued after the effective date of these rules such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions which pro-rate the required fee amount.

E. ARM 17.8, Sub-Chapter 7, Permit, Construction and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.704 General Procedures for Air Quality Pre-construction Permitting. An air quality pre-construction permit shall contain requirements and conditions applicable to both construction and subsequent use.

2. ARM 17.8.705 When Permit Required--Exclusions. Permits are required for operations that have the potential to emit greater than 25 tons/year of any pollutant. The permitted facility has the potential to emit greater than 25 tons per year of a regulated pollutant; therefore, a permit is required.

3. ARM 17.8.706 New or Altered Sources and Stacks Permit Application Requirements. This rule requires that an application for an air quality permit be submitted for a new or altered source or stack. The current permit action is considered an administrative permit action and does not require submittal of a permit application.

4. ARM 17.8.710 Conditions for Issuance of Permit. This rule requires that the source demonstrate compliance with applicable rules and standards before a permit can be issued. Also, a permit may be issued with such conditions as are necessary to assure compliance with all applicable rules and standards. YELP has demonstrated compliance with applicable rules and standards as required for permit issuance.

5. ARM 17.8.715 Emission Control Requirements. YELP is required to install on a new or altered source the maximum air pollution control capability which is technically practicable and economically feasible, except that BACT shall be utilized. The current permit action is considered an administrative permit modification and does not require a BACT analysis.

6. ARM 17.8.716 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the department at the location of the source.

7. ARM 17.8.717 Compliance with Other Statutes and Rules. This rule states that issuance of this permit does not relieve the permit holder of the responsibility of compliance with any other applicable federal and Montana statutes, rules and standards.

8. ARM 17.8.720 Public Review of Permit Applications. This rule requires that YELP notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. The current permit action is considered an administrative permit action and does not require public notice.

9. ARM 17.8.731 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may

be less than 1 year after the permit is issued.

10. ARM 17.8.733 Modification of Permit. An air quality permit may be modified for changes in any applicable rules and standards adopted by the board or changed conditions of operation at a source or stack which do not result in an increase in emissions because of those changed conditions of operation. A source may not increase its emissions beyond those found in its permit unless the source applies for and receives another permit.

11. ARM 17.8.734 Transfer of Permit. This section states an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the department.

F. 17.8, Sub-Chapter 8, Prevention of Significant Deterioration (PSD), including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this sub-chapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modification-- Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the Federal Clean Air Act (FCAA) that it would emit, except as this subchapter would otherwise allow.

   The current permit action is considered an administrative permit action and does not involve any increase in emissions.

G. ARM 17.8, Subchapter 12, Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:

   a. A potential to Emit (PTE) > 10 tons/year of any 1 hazardous air pollutant (HAP), PTE > 25 tons/year of a combination of any HAPs, or a Lesser quantity as the department may establish by rule,

   b. PTE > 100 tons/year of any pollutant, or

   c. Sources with the PTE > 70 tons/year of PM-10 in a serious PM-10 nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. YELP submitted a Title V operating permit application on June 12, 1996.

III. Emission Inventory

Calculation of annual average BTU/hr value for the boilers combined:

Lbs of coke per hour = 58,111

Lbs of coker gas per hour = 110,000

$$58{,}100 \text{ lb/hr} * 14{,}400 \text{ BTU/lb} + 110{,}000 \text{ lb/hr} * 673.4 \text{ BTU/lb} = 911 \times 10^6 \text{ BTU/hr}$$

The maximum coke feed rate is not expected to exceed 173,000 lbs/hr. The feed rate of coker gas is expected to be below the 110,000 lbs/hr identified in the above equation and will be dependant on Exxon's process. When cat slurry oil is combusted in the boiler, the amount of coke feed will be reduced.

The allowable emissions from the facility are identified in the permit. The permit limits the hourly emissions and the annual emissions from the main stack. In addition, permit #2650-05 limits the annual emissions from the coke unloading crushing/processing plant and the coke barn. Further, the permit includes a grain loading limit for all baghouses at the facility.

Emission Inventory (permit #2650-05): Off-Site Petroleum Coke Unloading, Crushing, Processing, Storage, and Handling.

	Tons/yr					
Source	TSP	PM-10	NO_x	VOC	CO	SO_x
Crushing/Processing plant w/ Baghouse	5.26	5.26	0	0	0	0
Coke Barn Storage and Handling	16.86	8.43	0	0	0	0
Haul Roads	2.74	1.23	0	0	0	0
Total	24.86	14.92	0	0	0	0

Emission Inventory (permit #2650-07):

	Tons/yr					
Source	TSP	PM-10	NO_x	VOC	CO	SO_x
Crushing/Processing plant w/ Baghouse	4.07	4.07	0	0	00	
Coke Barn Storage and Handling	14.12	7.06	0	0	0	0
Off-Site Coke Pile Forming (Exxon Pile)	3.50	1.75	0	0	0	0
Haul Roads	2.74	1.23	0	0	0	0
Total	24.43	14.11	0	0	0	0

- The department considers dumping of off-site coke at the existing Exxon coke pile to be part of the same off-site coke processing/handling activities permitted under permit action #2650-05.

  Potential total particulate matter (PM) emissions resulting from the dumping of off-site coke (35,000 tons) at the Exxon pile are 3.5 tons/yr. Because these potential emissions were not accounted for in permitting action #2650-05, which established limits keeping YELP out of NSR/PSD review for coke (off-site) processing activities at the plant, and because YELP wishes to stay out of NSR/PSD review for the current permit action #2650-07, combined production at the crushing facilities, while off-site coke is being dumped and stored at the Exxon pile, must be restricted to a level that would result in a reduction of 3.5 tons/yr potential PM emissions to allow for the increased potential PM emissions resulting from off-site coke dumping at the Exxon pile. This limit of 202,000 tons during any rolling 12 month time period, established in Section II.H.2.b of permit #2650-07, applies when off-site coke is being dumped/stored at the Exxon Refinery coke storage area, otherwise, the original production limit of 240,900 tons during any rolling 12 month time period, established in permit #2650-05, applies.

- A complete emission inventory for the YELP facility is on file with the department.

IV. Air Quality Impacts

The current permit action is considered an administrative permit modification and does not involve permitting any additional emissions. Therefore, the department does not believe the current permit action will result in any adverse impacts to the local air quality.

V. Best Available Control Technology Analysis

A BACT determination is required for each new or altered source. YELP shall install on the new or altered source the maximum air pollution control capability which is technically practicable and economically feasible, except that best available control technology shall be utilized. The current permit action is an administrative permit action and does not require a BACT analysis.

VI. Existing Air Quality

EPA determined the State Implementation Plan (SIP) did not protect the ambient standards for SO_2 in the Billings area, which is where the YELP facility is located. The state has prepared a revised plan to protect the standards. The allowable emissions from the YELP facility have been included in the proposed SIP revision.

The SIP revision was submitted by the department to EPA on September 6, 1995, for approval. To date, the department has not received a response from EPA.

VII. Taking or Damaging Implication Analysis

As required by 2-10-101 through 105, MCA, the department has conducted a private property taking and damaging assessment and has determined there are no taking or damaging implications.

VIII. Environmental Assessment

The current permit action is considered an administrative permit action and does not require an environmental assessment.

Permit Analysis Prepared by: M. Eric Merchant, MPH
Date: March 6, 2001